Baytex Energy Ltd.

1998 ANNUAL REPORT

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The Annual and Special Meeting of Shareholders of Baytex Energy Ltd. will be held in the Alberta Room of the Palliser Hotel at 133-9th Avenue S.W., Calgary, Alberta, on Tuesday, May 25th, 1999 at 3:00 p.m. (Calgary Time). All shareholders and other interested parties are invited to attend.

Our long-term perspective

WE REMAIN FOCUSED ON DEVELOPING OUR ASSET BASE

Baytex Energy Ltd. is a Calgary-based, Canadian oil and natural gas exploration, development and production company with a mandate to create shareholder value through exploration, development and asset acquisitions in select core areas. Baytex has grown from a startup company with fewer than 100 barrels of oil equivalent production per day and six employees in 1994 to 95 employees and 15,000 barrels of oil equivalent production at the end of 1998. The Company has a sound balance sheet, an excellent asset base and a vigorated team of employees to pursue growth and create value in the current challenging environment.

Providing the detail

BEHIND THE NUMBERS

FINANCIAL

($ thousands, except per share amounts)	**1998**	1997
Gross revenue	**102,337**	123,839
Cash flow from operations	**43,920**	63,879
per share – basic	**1.29**	2.10
– fully diluted	**1.25**	2.01
Net income (loss)	**(38,382)**	10,989
per share – basic	**(1.12)**	0.36
– fully diluted	**(1.12)**	0.36
Capital expenditures, net	**39,314**	166,654
Working capital (deficiency)	**42,050**	(32,342)
Long-term debt	**157,093**	98,555
Total net debt	**115,043**	130,897
Shares outstanding at December 31		
basic	**35,332**	33,791
fully diluted	**38,362**	35,053

Net loss incurred in 1998 was primarily due to a $38.1 million ceiling test writedown of the Company's petroleum and natural gas assets based on the low oil price at year end.

Capital expenditures in 1998 are net of $89.1 million of property dispositions that were negotiated in the last half of 1998 in order to strengthen the Company's financial position.

Long-term debt, net of working capital, was $115 million at December 31, 1998 or 2.6 times trailing cash flow.

OPERATING

	1998	1997
Production		
Conventional oil & ngls (bbls/d)	5,475	6,053
Heavy oil (bbls/d)	3,517	2,842
Total oil & ngls (bbls/d)	8,992	8,895
Natural gas (mmcf/d)	75.9	78.7
Barrels of oil equivalent (boe/d)	16,582	16,765
Reserves, proven & probable		
Oil & ngls (mbbls)	83,202	84,139
Natural gas (mmcf)	150,013	272,967
Barrels of oil equivalent (mboe)	98,203	111,436
Present value of reserves ($000s)		
(discounted at 15% before taxes)	455,466	636,048
Undeveloped land holdings (000s)		
Gross acres	1,079	1,323
Net acres	934	1,094

Heavy oil production grew in the last half of 1998 with the development of the Hoosier property in western Saskatchewan. Baytex has significant growth potential in its heavy oil production pending the recovery of oil prices.

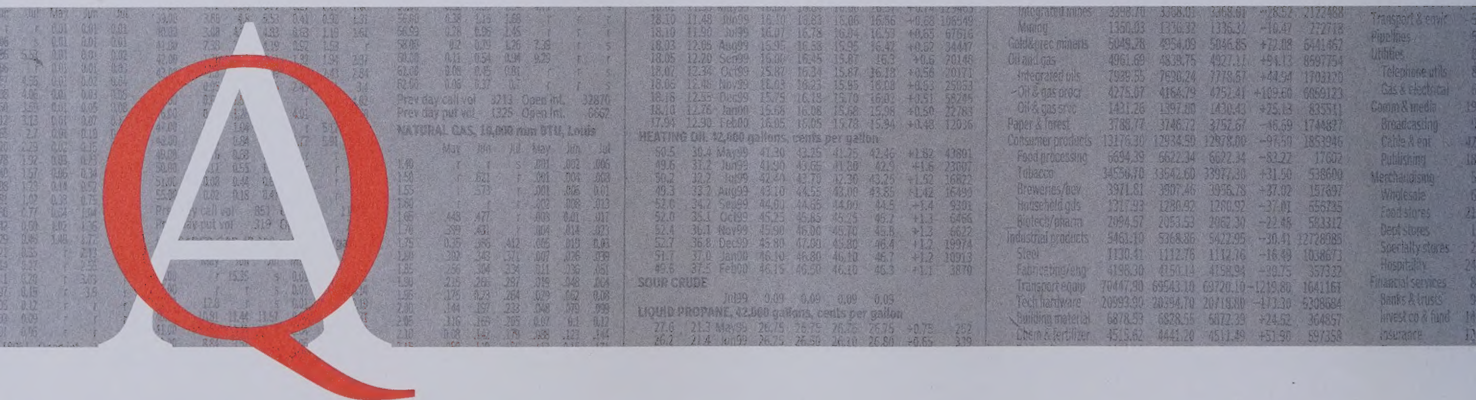
Natural gas production was affected by the Company's asset divestiture program in the fourth quarter of 1998 and was reduced to 55 million cubic feet per day in the first quarter of 1999 after the divestitures.

Net asset value at year-end 1998 was $9.07 per share based on established reserve value discounted at 15 percent.

Providing the answers

BEHIND THE QUESTIONS

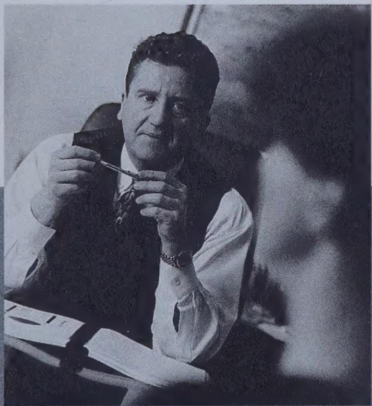
PRESIDENT AND CEO DALE SHWED ADDRESSES ISSUES THAT AFFECTED THE INDUSTRY IN 1998 AND THE STRATEGY FOR BAYTEX IN 1999.

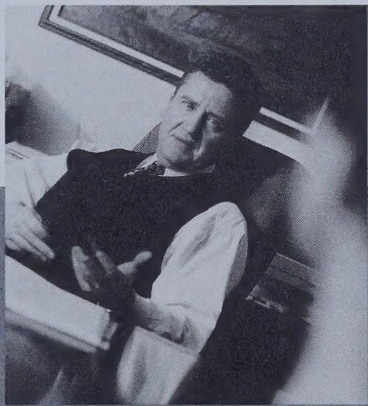


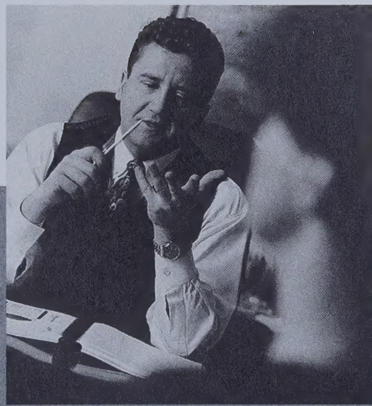
How would you characterize the past year for Baytex?

A. Two words best describe 1998 for Baytex: opportunity and challenge. Baytex merged with Dorset Exploration Ltd. in late 1997. The full impact of this transaction was not realized until late 1998 when the operations of the two companies became fully integrated. From an operational and financial perspective I believe the Dorset merger was, and continues to be, very positive for Baytex. We quadrupled our undeveloped land base and tripled our oil and natural gas production. More importantly, the transaction created a company with a tremendous asset base with identified growth opportunities and significant cash flow to weather a turbulent commodity price environment.

At the time of the acquisition Baytex had 35 employees and Dorset had 70 employees. As in most corporate mergers, the most challenging issue was the successful combination of two different corporate cultures. This presented logistical and organizational challenges, which have been successfully addressed, and today Baytex is a much stronger company. The merger created expectations that Baytex was capable of its previous level of growth, which, as it turned out, we did not achieve. There are a number of reasons for this. In the first quarter of 1998, we embarked on an aggressive drilling program; however, at the time, Baytex did not have the necessary systems or people in place to ensure the successful implementation of a program of this magnitude. The low oil price environment during 1998 substantially hindered our capital expenditures and caused us to revise our business plan and devise a new strategy that reflected the unfavorable pricing environment.







DALE SHWED
PRESIDENT AND CHIEF EXECUTIVE OFFICER

APRIL 8,1999

We recognized the problem and moved quickly to rectify it. In the third quarter of 1998, we reduced our capital program and focused on reducing costs. A successful divestiture program in the fourth quarter restored the financial health of the Company and allows for greater operating flexibility. We also made some significant organizational changes in order to pursue growth during these challenging times.

Based on your initiatives during the year, how did Baytex perform in 1998?

A. From an operational perspective, I believe Baytex made some important changes that provided good results in the last half of 1998 and established a stronger base to build on in 1999 and beyond. We have put together an exceptional team of people who can exploit the strengths of this company and add value. Our asset base is strong, as evidenced by our ability to add new production with a modest capital program in the last half of the year.

The depressed oil price through 1998 had a significant impact on Baytex's cash flow and earnings. The Dorset merger pushed the oil component of our reserves up to 83 percent and resulted in a ceiling test writedown of $38.1 million using the low oil price at year end. However, despite low oil prices we have maintained a net asset value of $9.07 per share which is far above our current trading price. Recently our efforts to increase natural gas reserves and production have met with very encouraging results.

One of the key issues facing Baytex in 1998 was managing its financial position. What strategies did you use to address this issue?

A. We knew we had to bring our debt in line and in the fourth quarter of 1998 we saw a window of opportunity. Recognizing that oil prices were not going to recover quickly, we disposed of some assets that did not match our ongoing strategy and were located in highly competitive areas. Because of the timeliness of this decision, we received excellent bids for our properties and raised $85 million which was applied to our long-term debt. This also resulted in a consolidation of our activities into three core areas which helped reduce our overall cost structure and improve efficiency.

We also completed a private placement of fixed rate term notes with U.S. institutional investors for US$57 million. By year-end 1998, we brought our total debt down to $115 million from $203 million at the end of the third quarter. Currently, Baytex has bank loans equal to less than one year's cash flow and has a significant undrawn credit facility.

What was the turning point for Baytex?

A. In June of 1998, I set out some specific goals for the Company, including the restructuring of the Company's management team. In July, Garry Wasylycia was promoted to the position of Vice-President, Exploration. In October, Ray Chan joined Baytex as Senior Vice-President, Chief Financial Officer and Director and John Leach was appointed Vice-President, Finance and Administration. In January 1999, Deric Orton joined Baytex as Vice-President, Land.

These management changes paid immediate dividends and I believe that Baytex is a much stronger Company today. The addition of Ray Chan has introduced a depth and breadth of expertise, specifically in the understanding of financing and reporting requirements of an intermediate-sized company and in communicating with the financial community. On the exploration side, we have completed a thorough review of our prospects and their economics and feel confident that we have the people and the prospects to add value through a conservative, cash flow driven capital program.

How will Baytex continue to grow in 1999 and beyond?

A. With an unstable commodity price environment the first and most important goal for 1999 is to protect the Company's balance sheet. We will drill natural gas prospects in the first quarter of 1999 and will continue to emphasize natural gas exploration and development as long as oil prices remain low. Should oil prices recover, Baytex has identified over 140 heavy oil drilling locations that can provide additional production growth. We will also continue to evaluate opportunities for select asset acquisitions.

We realized some notable successes in our natural gas program in the last six months, which will be the basis for continued exploration and development in 1999. We have initially identified seven gas prospects, each targeting 10 to 50 billion cubic feet of reserves. We have drilled four of these prospects to date, all being successful. With our large undeveloped land base of 934,000 net acres, Baytex has the inventory to continue growing in our chosen core areas.

At year-end 1998 our production portfolio was 37 percent natural gas, 34 percent light oil and 29 percent heavy oil. Our strategy is to move back to the 50/50 balance of gas and oil production that we had prior to the merger with Dorset. We believe that our natural gas drilling program in 1999 will move us closer to that target. We will only develop our heavy oil if we can achieve a reasonable rate of return. With today's narrow differential between the realized price of light and heavy oil, we are able to reactivate some of our heavy oil development plans. In January 1999 our wellhead price for heavy oil was $11.03 based on WTI at US$12.49, compared with $6.66 in January 1998 with WTI at US$16.73. If WTI returns to US$12.50 we will defer further development. However, should WTI prices stay over $13.50 we have tremendous upside in heavy oil and have the potential to increase production by 7,000 to 10,000 barrels per day.

In terms of other growth opportunities, we have some flexibility in the balance sheet to pursue strategic acquisitions. We are looking for opportunities to enhance our position within our core areas.

Finally, and I believe most importantly, the single greatest factor impacting our ability to grow is our team. Our management team and our employees are committed to the growth of Baytex.

What are the most important yardsticks of performance that you are using to guide Baytex over the next few years?

A. Going forward, we always want to maintain financial flexibility. We will maintain a debt to cash flow ratio of three times or less to ensure that flexibility. We are focusing on reducing costs company wide, with particular emphasis on operating costs. Baytex is a lean organization with G&A costs of around $0.55 per barrel of oil equivalent. Our operating costs per barrel of oil equivalent have decreased from $5.33 in 1997 to $4.97 in 1998 and we expect further reductions in 1999. Because we sold 15.5 million barrels of oil equivalent of reserves and moved 7.5 million barrels of oil equivalent of proven undeveloped reserves to proven developed reserves, it is more meaningful to look at our two year finding and development costs. On this basis, our finding and development costs are $5.61 per barrel of oil equivalent based on proven reserves and $3.55 based on proven plus probable reserves. These finding costs yielded a recycle ratio of 1.6 on proven reserves and 2.5 on proven plus probable reserves during a time of historically low oil prices. We are satisfied with these numbers and believe they show the increasing efficiency we are achieving after the merger.

We have also replaced 300 percent of our production with proven reserves and 480 percent with proven plus probable reserves. As evident by this track record, I believe we have the technical expertise, asset base and most importantly the discipline to continue to create value and deliver consistent growth to our shareholders.

RAYMOND CHAN
SENIOR VICE-PRESIDENT
AND CHIEF FINANCIAL OFFICER

JOHN LEACH
VICE-PRESIDENT, FINANCE AND ADMINISTRATION

DALE SHWED
PRESIDENT AND CHIEF EXECUTIVE OFFICER

GARRY WASYLYCIA
VICE-PRESIDENT, EXPLORATIO

Strength

THROUGH EXPERIENCE

The single greatest factor influencing our ability to achieve future growth is our team. Baytex's management team and each employee is committed to pursuing growth and creating value for our shareholders.

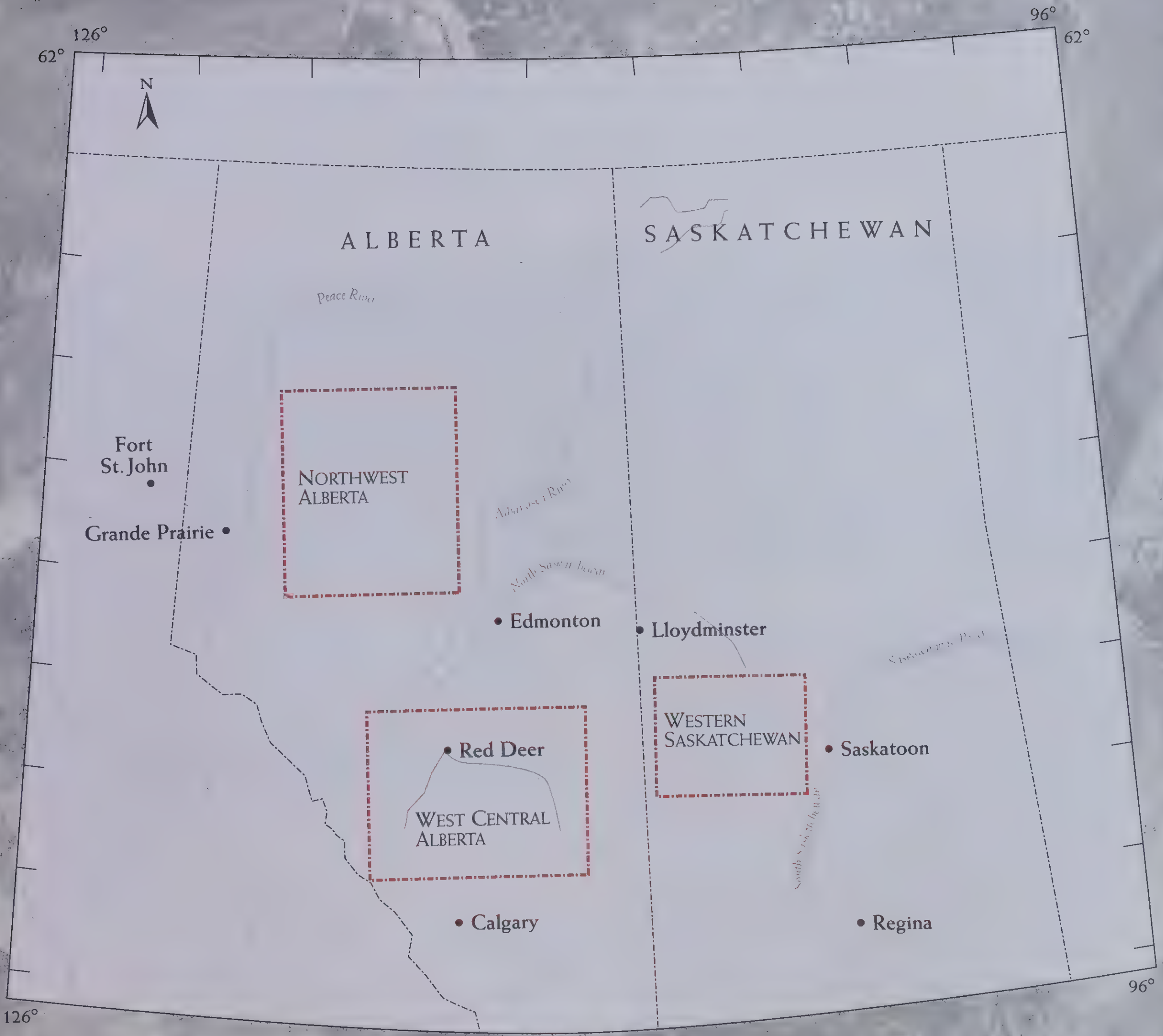
RICHARD NADEN
VICE-PRESIDENT, PRODUCTION

DALE MCAULEY
VICE-PRESIDENT, OPERATIONS

DERIC ORTON
VICE-PRESIDENT, LAND

Operational Analysis

REVIEW OF CORE AREAS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Calgary
Regina
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Exploration / Development

Baytex's three core areas offer tremendous opportunities for growth. During 1999, Baytex will focus its activities on natural gas exploration and development. Heavy oil exploitation during the year will be predicated on the sustained recovery of oil prices.

Northwest Alberta
Natural Gas

BAYTEX CONTROLS 610,000 NET ACRES OF UNDEVELOPED LAND IN NORTHWEST ALBERTA AND PRODUCES NATURAL GAS LARGELY FROM THE RED EARTH, GOODFISH, LAFOND, DARWIN AND GOLD CREEK AREAS. PRODUCTION GREW FROM 34.8 TO 41.8 MILLION CUBIC FEET PER DAY IN 1998 PRIOR TO THE ASSET DISPOSITIONS IN THE FOURTH QUARTER. A WINTER DEVELOPMENT PROGRAM OF 17 WELLS TARGETING SHALLOW BLUESKY GAS PROSPECTS ADDED AN AGGREGATE OF 10 MILLION CUBIC FEET PER DAY OF PRODUCTION BY MARCH 1999. IN ADDITION, BAYTEX PLANS TO DRILL SEVEN EXPLORATORY LOCATIONS DURING THIS WINTER. THE RESULTS OF THIS DRILLING PROGRAM WILL BE EVALUATED DURING THIS SUMMER IN ORDER TO ESTABLISH THE DEVELOPMENT PROGRAM FOR THE WINTER OF 2000.

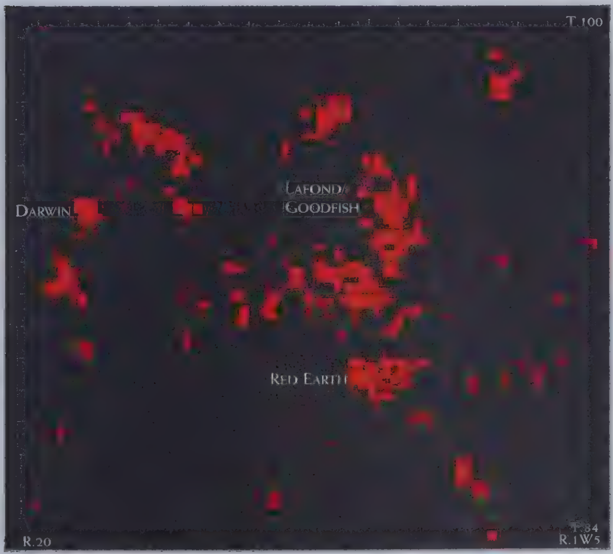
Red Earth/Goodfish/Lafond

Baytex owns 226,000 net acres of undeveloped land in this area, with gas production from the Bluesky sandstone and oil production from the Granite Wash and Slave Point formations. In 1998, Baytex drilled a total of 44 wells in this area which resulted in 12 oil wells, 13 gas wells, six service wells and 13 abandonments. Baytex currently produces approximately 1,100 barrels per day of oil and 21 million cubic feet per day of gas from this area. A 1999 winter drilling program of 15 (13.75 net) wells targeting Bluesky gas was successful in adding an estimated 8 million cubic feet per day of deliverability.

Darwin

Baytex holds approximately 5,900 net acres of undeveloped land and produces 4.1 million cubic feet per day of gas in the Darwin area. In the winter of 1999, Baytex participated as operator in a plant expansion which increased capacity from 10 to 20 million cubic feet per day (5.3 million cubic feet per day net). A winter drilling program of three (1.2 net) wells added an incremental 1.9 million cubic feet per day to Baytex.

NORTHWEST ALBERTA



CURRENT PRODUCTION:
- 1,200 BBLS/D OF OIL
- 28 MMCF/D OF GAS

FACILITY CAPACITY:
- 4,500 BBLS/D OF OIL
- 34 MMCF/D OF GAS

UNDEVELOPED LAND:
- 610,000 NET ACRES

WEST CENTRAL ALBERTA
LIGHT OIL AND NATURAL GAS

BAYTEX CURRENTLY PRODUCES APPROXIMATELY 3,200 BARRELS PER DAY OF LIGHT OIL AND 27.5 MILLION CUBIC FEET PER DAY OF NATURAL GAS IN THE WEST CENTRAL ALBERTA AREA. AT YEAR END, BAYTEX HELD 206,000 NET ACRES OF UNDEVELOPED LAND. ACTIVITIES IN 1998 WERE FOCUSED IN ALDER FLATS, WITH THE ADDITION OF 1,300 BARRELS OF OIL EQUIVALENT PER DAY OF PRODUCTION. OTHER ACTIVITIES INCLUDED A BELLY RIVER POOL DISCOVERY AT FERINTOSH AND EXTENSION OF THE BASAL BELLY RIVER POOL AT WESTEROSE.

PLANS FOR 1999 INCLUDE A FOCUS ON NATURAL GAS THROUGH DEVELOPMENT DRILLING WITHIN THE PRODUCING PROPERTIES, EXPLORATION ON UNDEVELOPED LANDS SUCH AS THE WILLESDEN GREEN ACREAGE AND STRATEGIC ACQUISITION OPPORTUNITIES

Leahurst/Ferintosh

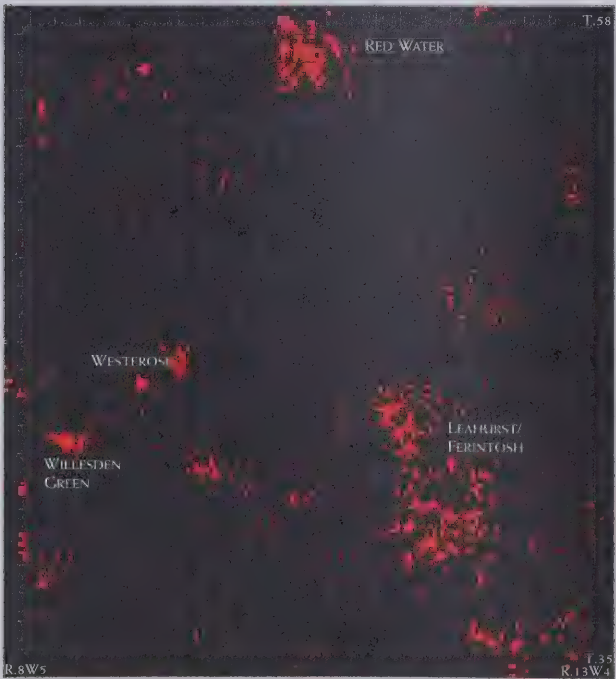
Leahurst/Ferintosh continued to be an active area for Baytex in 1998 with 18 wells drilled. Results from this program included ten gas wells, one oil well, one suspended gas well and six abandonments. Current production is 10 million cubic feet per day. Baytex holds 88,000 net acres of undeveloped land, interests in two gas plants and a 109-kilometre gathering system in this area. Year-round accessibility allows the Company to efficiently drill and bring shallow gas prospects on stream. Plans for 1999 include the acquisition of geophysical data to detail the Company's prospect inventory and the drilling of up to four locations.

Westerose

In the Westerose area, Baytex holds 10,400 net acres of undeveloped land and produces approximately 1,300 barrels per day from the Basal Belly River and Banff formations. In 1998, Baytex successfully expanded its Basal Belly River light oil pool through

a farm-in and the drilling of six horizontal wells. A waterflood program has delivered positive results by reducing gas-oil ratios and increasing production volumes. On the basis of these results, GPP (Good Production Practice) was received in late 1998. Baytex has identified several additional locations in this area.

West Central Alberta



Current Production:
– 3,200 bbls/d of oil
– 27.5 mmcf/d of gas
Facility Capacity
– 16,050 bbls/d of oil
– 46.9 mmcf/d of gas
Undeveloped Land:
– 206,000 net acres

Western Saskatchewan
Heavy Oil

BAYTEX'S WESTERN SASKATCHEWAN HEAVY OIL AREA PRODUCES APPROXIMATELY 4,500 BARRELS PER DAY FROM THE CARRUTHERS, HOOSIER, REWARD AND SUPERB PROPERTIES. THE RECENTLY DEVELOPED HOOSIER PROJECT AND THE CARRUTHERS AREA ACCOUNT FOR 90 PERCENT OF THIS PRODUCTION. BAYTEX HELD 118,000 NET ACRES OF UNDEVELOPED LAND IN THIS AREA AT YEAR-END 1998. ACTIVITIES IN 1998 INCLUDED THE DRILLING OF 67 WELLS RESULTING IN 35 OIL WELLS, 24 SUSPENDED OIL WELLS, ONE GAS WELL, THREE INJECTORS AND FOUR ABANDONMENTS. OF THE 24 SUSPENDED WELLS, 20 ARE LOCATED IN CARRUTHERS AND CONSIST OF A PAD OF 12 SLANT WELLS AND EIGHT OUTPOST LOCATIONS. THESE WELLS WILL BE COMPLETED AND EVALUATED AS OIL PRICES IMPROVE.

BAYTEX IS COMMITTED TO DEFERRING ITS HEAVY OIL DEVELOPMENT OPPORTUNITIES UNTIL OIL PRICES RECOVER ABOVE THE WTI US$13.50 RANGE. CAPITAL EXPENDITURES FOR THIS AREA IN 1999 WILL BE ALLOCATED TOWARDS LAND RETENTION, SELECT EXPLORATORY OPPORTUNITIES AND STRATEGIC ACQUISITIONS.

Hoosier

In December 1997, Baytex shot a 4.8 square mile 3-D seismic program on this Basal Mannville prospect, which was defined by six wells on five sections of 100 percent acreage. Final interpretation of the seismic led to the drilling of 25 vertical and 11 horizontal wells over a seven-month period, resulting in 26 oil wells, four suspended oil wells, three water injectors and three abandonments. Baytex also constructed a battery which became operational in October 1998. Production volumes increased from 60 barrels per day to a peak of 3,000 barrels per day, with current levels at approximately 2,000 barrels per day.

Plans for 1999 include the implementation of a waterflood, installation of high-volume pumps and the assessment of reduced spacing (20 acre) infill drilling. In 1999, Baytex has plans to drill one to three exploratory/outpost locations on its 7,400 net acres of undeveloped land in the Hoosier area.

Carruthers

In this area, Baytex holds 8,100 acres of undeveloped land and produces approximately 2,000 barrels per day from the Lower Mannville Cummings formation. Approximately 80 percent of the production is derived from the northern pool, which was exploited using horizontal well bores. The balance is derived from the southern pool through a 12-well delineation program drilled between November 1997 and May 1998. Drilling results consisted of nine oil wells, two suspended oil wells and one suspended gas well. Production rates from these wells range from 38 to 70 barrels per day. In October 1998, Baytex drilled a 12-well pad using slant-hole technology.

Plans for 1999 are dependent on improved pricing and include completion of the 12-well pad and development drilling from an inventory of 130 locations.

Reward

During 1998, Baytex drilled five (4.4 net) wells at Reward, which resulted in three (2.4 net) oil wells and two shut-in oil wells. Net production from these wells is approximately 200 barrels per day. Baytex recently purchased additional Crown lands on this play and holds 6,500 acres of undeveloped land in the area. Eight development locations have been identified and drilling has been deferred pending improved oil prices. Plans for 1999 include the drilling of two locations and seismic acquisition.

Superb

At Superb, Baytex holds 9,400 acres of undeveloped land and produces approximately 300 barrels per day from the Upper Mannville McLaren channel sand. Baytex has five locations in inventory, with an additional nine contingent locations to be drilled when oil prices improve. Plans for 1999 include seismic acquisition and one potential location for drilling.

WESTERN SASKATCHEWAN

CURRENT PRODUCTION:
- 4,900 BBLS/D OF OIL
- 1.5 MMCF/D OF GAS

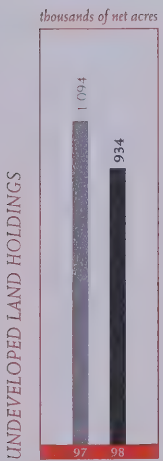
FACILITY CAPACITY:
- 8,700 BBLS/D OF OIL

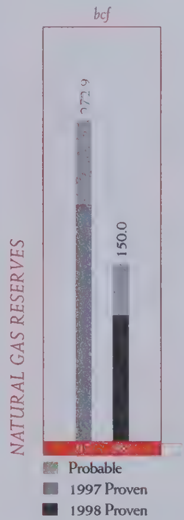
UNDEVELOPED LAND:
- 118,000 NET ACRES

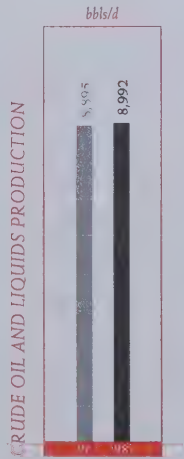
Operational Analysis

REVIEW OF OPERATIONS

THE COMPLETION OF THE SUCCESSFUL ASSET DIVESTITURE PROGRAM IN 1998 HAS SIGNIFICANTLY STRENGTHENED BAYTEX'S FINANCIAL POSITION AND PROVIDED THE COMPANY WITH FLEXIBILITY IN THE CURRENTLY UNSTABLE OIL PRICE ENVIRONMENT. THE COMPANY WILL FOCUS EFFORTS IN 1999 ON THE DEVELOPMENT OF NATURAL GAS PROSPECTS IN NORTHWESTERN ALBERTA WITH AN EMPHASIS ON MAXIMIZING THROUGHPUT OF EXISTING FACILITIES. BAYTEX WILL ALSO BE PURSUING SEVEN NATURAL GAS EXPLORATION PROSPECTS EACH TARGETING 10 TO 50 BILLION CUBIC FEET OF NATURAL GAS RESERVES. DEVELOPMENT OF BAYTEX'S HEAVY OIL RESERVES WILL BE DEFERRED PENDING A SUSTAINED RECOVERY OF WORLD OIL PRICES ABOVE US$13.50. IF AN OIL PRICE RECOVERY OCCURS, THE COMPANY HAS 140 FIRM DRILLING LOCATIONS IDENTIFIED AND AN ADDITIONAL 75 CONTINGENT LOCATIONS THAT COULD INCREASE HEAVY OIL PRODUCTION BY 7,000 TO 10,000 BARRELS PER DAY.







Drilling Industry statistics ranked Baytex eleventh in Alberta and sixth in Saskatchewan for most active drillers during 1998 with the drilling of 171 wells.

Reserves Net asset value remains strong at year-end 1998 despite lower oil prices as each Baytex share is supported by 1.9 barrels of oil equivalent of proven reserves or 2.8 barrels of oil equivalent of proven and probable reserves.

Production Baytex recorded significant production gains during the second half of 1998, averaging 16,686 barrels of oil equivalent per day in the third quarter and 18,038 barrels of oil equivalent per day in the fourth quarter, compared to 15,486 barrels of oil equivalent per day in the second quarter.

UNDEVELOPED LAND SUMMARY	1998			1997		
	GROSS ACRES	NET ACRES	AVERAGE INTEREST	GROSS ACRES	NET ACRES	AVERAGE INTEREST
Northwest Alberta	693,608	610,032	88%	890,827	723,058	81%
West Central Alberta	259,052	205,549	79%	277,193	229,567	83%
Saskatchewan	126,063	118,246	94%	154,680	141,188	91%
Total	1,078,723	933,827	87%	1,322,700	1,093,813	83%

Land

Nineteen ninety-eight was a year of consolidation, disposition and prioritization of the Company's land holdings. The acquisition of Dorset Exploration Ltd. in 1997 provided Baytex with the opportunity to consolidate its accumulated acreage inventories into concise focus areas. Lands which did not fit into these focus areas were sold to third parties concurrent with strategic acquisitions in Crown sales in areas such as Darwin, Red Earth, Leahurst, Superb and Carruthers. In 1998, the Company spent $4.14 million at land sales to acquire approximately 61,000 net acres. As a result of these efforts the Company's land inventory was maintained at 1,079,000 (934,000 net) undeveloped acres with an average working interest of 87 percent. Charter Land Services Ltd. has evaluated Baytex's undeveloped land at December 31, 1998 and has assigned a net market value of $47.3 million to this acreage position.

Drilling

During 1998, Baytex drilled a total of 171 (156.6 net) wells of which 105 (90.6 net) were in Alberta and 66 (66.0 net) were in Saskatchewan. According to industry statistics, Baytex ranked as the eleventh most active driller in Alberta and sixth in Saskatchewan.

The Company's 1999 plans call for a minimum of 40 wells to be drilled. This conservative forecast will increase with heavy oil exploitation drilling if a sustained recovery of oil prices above US$13.50 is experienced during the year, and by natural gas development drilling predicated on the success of the exploration program.

Drilling activity	Exploratory Gross	Exploratory Net	Development Gross	Development Net	Total Gross	Total Net
1998						
Crude oil wells	**8**	**7.5**	**83**	**80.5**	**91**	**88.0**
Natural gas wells	**11**	**10.0**	**36**	**28.6**	**47**	**38.6**
Dry and abandoned	**16**	**15.6**	**17**	**14.4**	**33**	**30.0**
Total wells	**35**	**33.1**	**136**	**123.5**	**171**	**156.6**
Success rate (%)	**54**	**53**	**88**	**88**	**81**	**81**
Average working interest (%)		**95**		**91**		**92**
1997						
Crude oil wells	9	9.0	70	59.2	79	68.2
Natural gas wells	19	18.2	30	24.5	49	42.7
Dry and abandoned	23	18.6	35	27.5	58	46.1
Total wells	51	45.8	135	111.2	186	157.0
Success rate (%)	55	59	74	75	69	71
Average working interest (%)		90		82		84

Production by area	Conventional oil and NGLs (bbls/d)	Heavy oil (bbls/d)	Natural gas (mmcf/d)	Barrel of oil equivalent (boe/d)
1998				
Northwest Alberta	**1,851**	**–**	**41.8**	**6,031**
West Central Alberta	**3,133**	**–**	**32.7**	**6,403**
Saskatchewan	**491**	**3,517**	**1.4**	**4,148**
Total production	**5,475**	**3,517**	**75.9**	**16,582**
1997				
Northwest Alberta	2,028	–	34.8	5,508
West Central Alberta	3,366	–	40.9	7,456
Saskatchewan	659	2,842	3.0	3,801
Total production	6,053	2,842	78.7	16,765

Production

Natural gas production in Northwest Alberta was 41.8 million cubic feet per day in 1998, an increase of 20 percent over the 34.8 million cubic feet per day produced during 1997. A successful shallow gas drilling program in the Goodfish area increased throughput to 17 million cubic feet per day in 1998 compared to 15.6 million cubic feet per day in the prior year.

A new facility at Darwin was commissioned in February 1998 yielding 3.9 million cubic feet per day of gas for the year. At Gold Creek a full year of production and drilling increased production from 0.6 million cubic feet per day in 1997 to 3.7 million cubic feet per day this past year, peaking at 5.8 million cubic feet per day prior to its disposition. Northwest Alberta oil production of 1,851 barrels per day in 1998 was nine percent lower than the 1997 rate of 2,028 barrels per day. Red Earth oil production decreased by 10 percent to 1,324 barrels per day in 1998 from 1,478 barrels per day in 1997 due to declines in new wells drilled from the year before. Current production from this area, after the 1998 property dispositions is, 28 million cubic feet per day of natural gas and 1,200 barrels per day of light oil and natural gas liquids.

Gas production in West Central Alberta totalled 32.7 million cubic feet per day in 1998 compared to 40.9 million cubic feet per day in 1997. Activity in this area was highlighted by the construction of the Alder Flats gas plant which went on stream in May 1998 contributing annualized rates of 4.7 million cubic feet per day. At the time of its disposition, this property was producing 9.0 million cubic feet per day of gas and 290 barrels per day of natural gas liquids.

Oil production declined seven percent in 1998 to average 3,133 barrels per day versus 3,366 barrels per day in 1997. With additional drilling at Westerose, production increased to 720 barrels per day in 1998. In January 1999 production rose to 1,200 barrels per day upon removal of allowable restrictions due to the implementation of a waterflood program. Current production from this area, after the 1998 asset disposition, is 27.5 million cubic feet per day of natural gas and 3,200 barrels per day of light oil and natural gas liquids.

In Western Saskatchewan, heavy oil production grew to 3,517 barrels per day in 1998, a 24 percent increase over the 2,842 barrels per day in 1997. Rates peaked at 5,400 barrels per day prior to year-end reductions relating to new well declines and suspension of wells due to low prices. Extension and development of the North Hoosier Basal Mannville pool added 2,700 barrels per day over the last four months of 1998. At Carruthers, oil production held steady at 2,000 barrels per day throughout the year due to eight new vertical wells. Drilling of the Waseca prospect at Reward grew production by a further 300 barrels per day by December 1998. Production at Superb was down, due to a five-month suspension caused by low prices, to average 160 barrels per day in 1998 versus 286 barrels per day in 1997. Light oil production at Manor in southeastern Saskatchewan declined from 659 barrels per day in 1997 to 491 barrels per day in 1998, as further development was deferred until prices recovered. Current production in Saskatchewan is 4,500 barrels per day of heavy oil, 400 barrels per day of light oil and 1.5 million cubic feet per day of natural gas.

Reserves

Baytex's fourth quarter divestiture program had a significant impact on the Company's year-end reserves with 15.5 million barrels of oil equivalent reserves sold. In addition, much of the Company's 1998 drilling program was dedicated to developing previously assigned proven undeveloped reserves. As a result, proven reserves declined to 65.0 million barrels of oil equivalent from 75.9 million barrels of oil equivalent in 1997. Proven plus probable reserves declined to 98.2 million barrels of oil equivalent in 1998 from 111.4 million barrels in 1997.

	Crude Oil and NGLs (MBBLS)			Natural Gas (MMCF)		
Reserves Reconciliation	Proven	Probable	Total	Proven	Probable	Total
December 31, 1996	21,963	6,224	28,187	184,474	56,965	241,439
Discoveries and extensions	34,554	20,156	54,710	65,539	21,181	86,720
Acquisitions	762	66	828	20,130	6,443	26,573
Dispositions	(536)	(127)	(663)	(4,906)	–	(4,906)
Revisions of prior estimates	2,269	2,055	4,324	(34,881)	(13,252)	(48,133)
Production	(3,247)	–	(3,247)	(28,726)	–	(28,726)
December 31, 1997	55,765	28,374	84,139	201,630	71,337	272,967
Discoveries and extensions	8,721	3,120	11,841	48,354	30,883	79,237
Acquisitions	–	–	–	–	–	–
Dispositions	(2,226)	(1,013)	(3,239)	(77,739)	(45,047)	(122,786)
Revisions of prior estimates	(4,583)	(1,674)	(6,257)	(38,817)	(12,884)	(51,701)
Production	(3,282)	–	(3,282)	(27,704)	–	(27,704)
December 31, 1998	**54,395**	**28,807**	**83,202**	**105,724**	**44,289**	**150,013**

	Reserves (Before Royalties)		Present Worth of Reserves Discounted at ($000s)		
December 31, 1998	Oil & Liquids (MBBL)	Gas (MMCF)	0%	10%	15%
Proven producing	16,721	55,937	252,278	178,448	156,296
Proven non-producing	9,957	31,708	146,675	90,066	74,563
Proven undeveloped	27,717	18,079	231,166	119,435	90,132
Total proven	54,395	105,724	630,119	387,949	320,991
Probable	28,807	44,289	388,377	179,367	134,475
Total proven and probable	**83,202**	**150,013**	**1,018,496**	**567,316**	**455,466**

Pricing Assumptions	WTI at Cushing, Oklahoma (US$/BBL)	Light oil at Edmonton (CDN$/BBL)	Heavy oil 12° API at Hardisty (CDN$/BBL)	Alberta spot gas (CDN$/MCF)
1999	14.25	20.68	12.79	2.25
2000	16.32	23.42	14.78	2.16
2001	17.69	25.03	16.08	2.23
2002	19.10	26.67	17.42	2.34
2003	20.02	27.56	18.27	2.46

Net asset value (*$ thousands*)	December 31, 1998	
Reserve discount rate	10%	15%
Established (proved + ½ probable reserves)	477,633	388,229
Undeveloped land	47,298	47,298
Long-term debt and working capital	(115,043)	(115,043)
Net asset value	409,888	320,484
Outstanding shares	35,332	35,332
Net asset value per share	$ 11.60	$ 9.07

Investment efficiency	2 year average	3 year average
Capital expenditures (000s)	**205,967**	316,064
Finding and development ($/boe)		
Proven	**5.61**	6.11
Proven and probable	**3.55**	4.02
Cash flow netbacks ($/boe)	**8.86**	9.43
Reserve recycle ratio		
Proven	**1.6**	1.5
Proven and probable	**2.5**	2.3
Reserve replacement ratio		
Proven	**3.0**	3.1
Proven and probable	**4.8**	4.7

Reserve life index	January 1999 production	Total proven	Proven and probable
December 31, 1998			
Crude oil and NGLs (bbls/d)	9,600	15.5	23.7
Natural gas (mmcf/d)	54.0	5.4	7.6
Oil equivalent (boe/d)	15,000	11.9	17.9

Marketing

Crude Oil

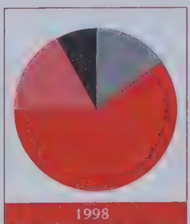
During 1998, world oil prices prevailed at their lowest levels since the mid 1970s. West Texas Intermediate (WTI) crude prices fell more than 30 percent to average US$14.43 in 1998 compared to US$20.61 in 1997. Fortunately, Canadian producers gained some relief through a weak Canadian dollar, as the average exchange rate declined to US$0.6743 in 1998 from US$0.7223 in 1997.

The majority of Baytex's crude oil is sold on the open market through a marketing agent. This allows Baytex to take advantage of the best pricing available. In 1999, the Company has hedged 4,000 barrels per day of its oil production at a fixed price of Cdn$20.51. This will allow Baytex to ensure its base capital program can be funded by a threshold cash flow and the necessary financial covenants be maintained.

Baytex has a broad mix of oil streams in Alberta and Saskatchewan. Fifty percent of the Company's 1998 crude oil sales consisted of light sweet oil produced in Alberta. The majority of the balance was made up of heavy oil sales from Saskatchewan properties. Baytex received an average price of $13.96 per barrel for its total oil and natural gas liquids sales in 1998 compared to $21.52 per barrel in 1997. Heavy oil averaged $9.69 per barrel in 1998 compared to $14.52 per barrel in 1997, with light oil and natural gas liquids averaging $16.70 per barrel in 1998 compared to $24.81 per barrel in 1997.

The most dramatic pricing change in 1998 was the large reduction in the differential between light oil and heavy oil pricing. In December 1997, the differential for Baytex's heavy oil production at Soda Lake, Saskatchewan was Cdn$17.04. For the same period in 1998, the differential had decreased to Cdn$6.83. Approximately 40 percent of Baytex's oil production benefits from this drop in differentials.

NATURAL GAS PORTFOLIO
percent

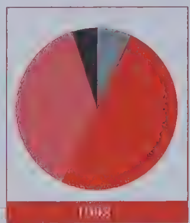


U.S. Midwest	15
AECO	60
Gulf Coast	17
U.S. Northeast	8

NATURAL GAS SALES
percent

Long-term	16
Short-term	41
Spot	10
Aggregator	33

CRUDE OIL MIX
percent



Alberta mixed sour	7
Alberta light sweet	50
Saskatchewan heavy	38
Natural gas liquids	5

Natural Gas

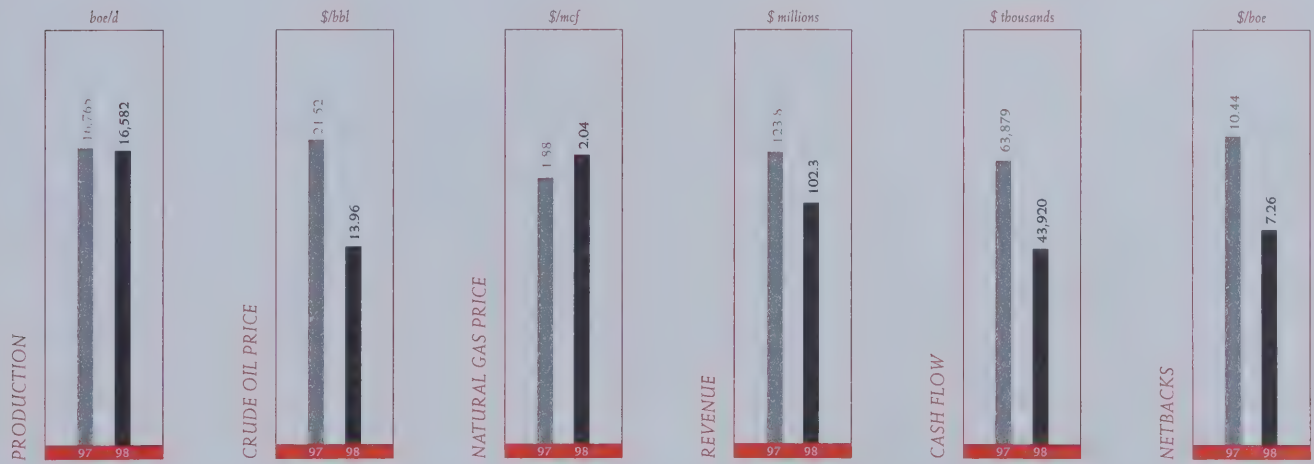
Canadian natural gas prices strengthened during 1998 primarily due to incremental pipeline capacity which came on stream in late 1998 from several pipeline projects: Northern Border, TransCanada and Pacific Gas. The additional capacity negated any restrictions on natural gas exports from Alberta and has allowed Canadian pricing to more closely match natural gas pricing in the U.S. As a result, the benchmark Alberta reference price increased to $1.93 per thousand cubic feet in 1998 from $1.84 per thousand cubic feet in 1997.

Baytex achieved an increase of 8.5 percent in gas prices in 1998, averaging $2.04 per thousand cubic feet compared to $1.88 per thousand cubic feet in 1997. Baytex continues to maintain exposure to a variety of markets for risk management purposes. The Company's natural gas market mix for 1998 was eight percent tied to the U.S. Northeast, 15 percent tied to the U.S. Midwest, 17 percent tied to the U.S. Gulf coast and 60 percent tied to Alberta prices. With 51 percent of its gas sales tied to spot market and short-term contracts based on pricing in Alberta, the Company was able to benefit from the strengthening of Alberta prices in 1998. Baytex will continue to employ a diversified sales portfolio to ensure premium pricing for its natural gas production.

Management's

DISCUSSION AND ANALYSIS

NINETEEN NINETY-EIGHT WAS A YEAR OF SIGNIFICANT CHALLENGES. A 30 PERCENT DROP IN OIL PRICES IN 1998 CAUSED OIL PRODUCERS TO FOCUS THEIR ATTENTION ON ASSET MANAGEMENT AND FISCAL RESTRAINT. BAYTEX BEGAN THIS ADJUSTMENT PROCESS EARLY IN 1998 BY REDUCING CAPITAL SPENDING AND CONCENTRATING ON COST AND DEBT REDUCTION. THE MAJORITY OF THE COMPANY'S LONG-TERM DEBT WAS CONVERTED INTO FIXED-RATE TERM DEBT MATURING IN NOVEMBER 2004. THE COMPANY HAS CREATED FINANCIAL STABILITY AND WILL CONTINUE TO HAVE OPERATIONAL FLEXIBILITY SHOULD OIL PRICES REMAIN LOW FOR A PROLONGED PERIOD. NATURAL GAS PRICES REMAINED STRONG IN 1998, WITH THE ALBERTA REFERENCE PRICE AVERAGING $1.93 PER THOUSAND CUBIC FEET, AN INCREASE OF FIVE PERCENT OVER 1997. BAYTEX TOOK ADVANTAGE OF THE STRONG NATURAL GAS MARKET BY DIVESTING OF GAS PROPERTIES WHICH RECEIVED AN AVERAGE SALES PRICE OF $32,000 PER PRODUCING BARREL OF OIL EQUIVALENT. BAYTEX'S STRATEGY FOR 1999 INCLUDES A DRILLING PROGRAM FOCUSED ON NATURAL GAS DEVELOPMENT AND EXPLORATION AS WELL AS STRATEGIC ASSET ACQUISITIONS.



Capital expenditures were significantly curtailed during the second half of 1998 to $47 million compared to $81 million in the first six months.

Operating expenses were reduced seven percent to $4.97 per barrel of oil equivalent in 1998 compared to $5.33 per barrel of oil equivalent in 1997.

Total net debt was reduced to $115 million at December 31, 1998 from $203 million at September 30 through a successful asset divestiture program.

Sales

Petroleum and natural gas sales decreased in 1998 to $102.3 million, 17 percent lower than the $123.8 million earned in 1997. This decrease was the direct result of lower world oil prices.

Oil and natural gas liquids sales decreased to $45.8 million, representing 45 percent of total sales in 1998 compared to $69.9 million on 56 percent of total sales in 1997. Production of oil and natural gas liquids averaged 8,992 barrels per day in 1998 compared to 8,895 barrels per day in 1997. Heavy oil accounted for 39 percent or 3,517 barrels per day of the Company's total 1998 oil and natural gas liquids production, compared to 32 percent or 2,842 barrels per day in 1997. Baytex received an average price of $13.96 per barrel for its total oil and natural gas liquid sales in 1998 compared to $21.52 per barrel in 1997. Heavy oil attracted an average price of $9.69 per barrel in 1998 compared to $14.52 per barrel in 1997 with light oil and natural gas liquids averaging $16.70 per barrel in 1998 compared to $24.81 per barrel in 1997.

Natural gas sales increased five percent to $56.5 million from $54.0 million in 1997, contributing 55 percent of total revenue. Natural gas production decreased four percent to 75.9 million cubic feet per day in 1998 from 78.7 million cubic feet per day in 1997. Baytex received an average price of $2.04 per thousand cubic feet for its natural gas sales in 1998 compared to $1.88 per thousand cubic feet in 1997.

Royalties

Royalties, which include Crown, freehold and overriding royalties net of Alberta Royalty Tax Credits (ARTC), decreased along with sales in 1998 to $14.7 million from $19.6 million in 1997. Royalties declined as a percentage of sales to 14.4 percent in 1998 from 15.8 percent in 1997. Oil and natural gas liquids royalties averaged $1.79 per barrel or 13 percent of sales compared to $3.32 per barrel or 15 percent of sales in 1997. This decrease was the result of a larger component of heavy oil production in 1998, which attracts a lower royalty rate than light oil and natural gas liquids. Heavy oil royalties averaged four percent of 1998 sales compared to light oil and natural gas liquids royalties averaging 16.1 percent. Gas royalties averaged $0.32 per thousand cubic feet or 15.6 percent of sales compared to $0.30 per thousand cubic feet or 15.9 percent in 1997. The lower rate was the result of higher gas cost allowance recoveries in 1998.

	1998		1997	
GROSS REVENUE ANALYSIS	$ THOUSANDS	$/UNIT	$ THOUSANDS	$/UNIT
Oil				
Conventional wellhead	33,369	16.70	54,817	24.81
Heavy wellhead	12,440	9.69	15,059	14.52
Combined wellhead	45,809	13.96	69,876	21.52
Gas				
Wellhead	56,528	2.04	53,963	1.88
Total gross revenue	102,337	16.91	123,839	20.24

Other Income

In 1998, other income was primarily made up of a foreign exchange gain on the settlement of a U.S. dollar transaction. The 1997 other income consisted mainly of interest earned on overpayments of prior years' natural gas Crown royalty estimates.

Operating Expenses

Operating expenses decreased eight percent in 1998 to $30.1 million ($4.97 per barrel of oil equivalent) from $32.6 million ($5.33 per barrel of oil equivalent) in 1997.

Operating expenses for total oil and natural gas liquids in 1998 decreased to $5.04 per barrel from $5.79 per barrel in 1997. Light oil and natural gas liquids operating costs decreased 12 percent from $5.45 per barrel in 1997 to $4.81 per barrel in 1998. Heavy oil operating costs reduced 17 percent from $6.52 per barrel in 1997 to $5.40 in 1998. These decreases were the result of concerted cost reduction efforts, new facilities to eliminate trucking and processing fees and the replacement of expensive propane with natural gas for lease fuel.

Natural gas costs per unit increased nominally to $0.49 per thousand cubic feet in 1998 from $0.48 in 1997. Natural gas costs are expected to decrease in 1999 as the Company benefits from development drilling to increase plant utilization.

General and Administrative Expenses

General and administrative costs (G&A) remained relatively constant at $3.4 million compared to $3.3 million in 1997. G&A averaged $0.56 per barrel of oil equivalent in 1998 compared to $0.54 per barrel of oil equivalent in 1997. Gross G&A decreased to $1.46 per barrel of oil equivalent in 1998 from $1.88 per barrel of oil equivalent in 1997, which is attributable to the merging of Baytex and Dorset and the elimination of duplicate costs.

GENERAL AND ADMINISTRATIVE EXPENSES

($ thousands)	1998	1997
Gross expense	**8,814**	11,496
Operator's recoveries	**(4,404)**	(4,278)
Subtotal	**4,410**	7,218
Capitalized expense	**(1,035)**	(3,907)
Net expense	**3,375**	3,311

Depletion and Depreciation

Depletion and depreciation prior to ceiling test considerations was $42.0 million for 1998 compared to $44.5 million in 1997. This represented $6.94 per barrel of oil equivalent in 1998, down from $7.27 per barrel of oil equivalent in 1997.

As required under the full cost method of accounting for oil and natural gas properties, Baytex applies an annual ceiling test to ensure capital costs, net of deferred income taxes, do not exceed the estimated value of future net revenues from oil and natural gas reserves. These revenues are calculated using year-end prices less future G & A, financing costs, and income taxes related to production

of those reserves. As a result of the test performed at December 31, 1998, the Company was required to recognize additional depletion and depreciation of $64.8 million and deferred income tax recovery of $26.7 million.

Baytex's provision for future site restoration costs totalled $2.2 million in 1998 compared to $2.6 million in 1997. This amount represented a charge to income for the estimated cost of future clean-up and restoration of producing and shut-in wells and facility sites. The Company's total estimated future site restoration liability at year-end 1998 decreased to $33.8 million from $35.8 million in 1997 as a result of the sale of properties in the last half of 1998.

Interest Expense

Interest expense increased to $10 million in 1998 compared to $4.3 million in 1997 due to increased drawings on the Company's credit facilities along with higher average interest rates in 1998. The average month-end debt for 1998 increased to $161 million compared to $94 million in 1997.

In November 1998 Baytex issued US$57 million of senior secured term notes bearing interest at 7.23 percent with principal repayments due on November 13, 2004. Proceeds from these notes were applied against outstanding borrowings from the Company's banking facility.

Income Taxes

The Company's current tax expense for 1998 consisted of a Large Corporation Tax levy of $0.7 million and a $0.3 million charge for Saskatchewan Capital Tax. The 1999 Large Corporation Tax should be lower due to the reduction in long-term debt and the ceiling test write-down. All other current income taxes have been deferred using the Company's accumulated tax pools.

CANADIAN TAX POOLS (*$ thousands*)	Dec. 31, 1998
Cumulative Canadian Exploration Expense	71,000
Cumulative Canadian Development Expense	108,000
Cumulative Canadian Oil and Gas Property Expense	15,000
Undepreciated Capital Cost	71,000
Other	5,000
Total tax pools	270,000

Net Income and Cash Flow from Operations

Cash flow from operations decreased 31 percent to $43.9 million from $63.9 million in 1997. Basic cash flow from operations decreased to $1.29 per share from $2.10 per share in 1997 while fully diluted cash from operations fell to $1.25 per share from $2.01 in 1997. The large drop in cash flow was the result of lower world oil prices.

Baytex incurred a net loss of $38.4 million in 1998 compared to net income of $11 million in 1997. The 1998 loss was essentially the result of the ceiling test write-down of $38.1 million after tax. Otherwise, the Company would have broken even in 1998 under the influence of low oil prices.

Capital Expenditures

Baytex drilled 171 (156.6 net) wells in 1998 with a success rate of 81 percent (net). Net capital expenditures totalled $39.3 million in 1998, a decrease of 76 percent over the $166.7 million spent in 1997. Net expenditures reflected $89.1 million of divestitures in the last half of the year.

Included in gross expenditures of $128.4 million for 1998 were $8.4 million on land purchases and lease rentals, $6.7 million on geological and geophysical expenditures, $19.0 million on exploration drilling and completions, $68.0 million on development drilling and completions, $24.8 million on facilities and $1.5 on capitalized G&A and office equipment.

CAPITAL EXPENDITURES (*$ thousands*)	1998	1997
Land	8,399	11,995
Seismic	6,655	12,276
Drilling and completions	87,110	97,779
Equipment	24,781	22,979
Acquisitions	–	27,930
Other	1,479	4,784
Total	128,424	177,743
Dispositions	(89,110)	(11,089)
Net capital additions	39,314	166,654

	CONV. OIL & NGL ($/BBL)		HEAVY OIL ($/BBL)		TOTAL OIL & NGL ($/BBL)		GAS ($/MCF)		BOE ($/BOE)	
	1998	1997	1998	1997	1998	1997	1998	1997	1998	1997
Sales price	16.70	24.81	9.69	14.52	13.96	21.52	2.04	1.88	16.91	20.24
Royalties	(2.99)	(4.83)	(0.45)	(1.17)	(2.00)	(3.67)	(0.35)	(0.34)	(2.67)	(3.52)
ARTC	0.30	0.43	0.06	0.13	0.21	0.35	0.03	0.04	0.24	0.32
Operating costs	(4.81)	(5.45)	(5.40)	(6.52)	(5.04)	(5.79)	(0.49)	(0.48)	(4.97)	(5.33)
Net revenue	9.20	14.96	3.90	6.96	7.13	12.41	1.23	1.10	9.51	11.71

	1998		1997	
CASH FLOW AND NET INCOME	$/BOE	PERCENT	$/BOE	PERCENT
Production revenue	16.91	100	20.24	100
Net royalties	(2.43)	(15)	(3.20)	(16)
Operating expenses	(4.97)	(29)	(5.33)	(26)
Net production revenue	9.51	56	11.71	58
General and administrative	(0.56)	(3)	(0.54)	(2)
Net interest	(1.52)	(9)	(0.58)	(3)
Current taxes	(0.17)	(1)	(0.15)	(1)
Cash flow from operations	7.26	43	10.44	52
Depletion and depreciation	(17.64)	(104)	(6.85)	(34)
Site restoration costs	(0.37)	(2)	(0.43)	(2)
Deferred taxes	4.41	26	(1.37)	(7)
Net income (loss)	(6.34)	(37)	1.79	9

Liquidity and Capital Resources

Baytex's capital expenditures and investments are financed through a combination of cash flow from operations, equity and debt financing. In 1998, the Company's cash flow from operations was $43.9 million, higher than the net capital spending of $39.3 million. The Company also received proceeds of $8.8 million from the issuance of shares. Consequently, outstanding debt at December 31, 1998 net of working capital was reduced to $115 million from $131 million at year-end 1997. Baytex's 1999 budgeted capital expenditure program is planned to be financed by cash flow from operations.

At year-end 1998, the Company's long-term debt was made up of two components. The first component consisted of US$57 million of senior secured term notes. These notes bear interest at 7.23 percent payable quarterly, with principal repayable on November 13, 2004. They are governed by financial and other corporate covenants and are secured by a charge over all of the Company's assets, which security is shared pari passu with the banking facilities. The second component consists of an operating loan and a revolving loan provided by a Canadian chartered bank. The facilities bear interest at the Bank's prime lending rate and are secured by a charge over all of the Company's assets, which security is shared pari passu with the senior secured term notes. The facilities are subject to annual review and include a total lending commitment of $85 million at December 31, 1998. Subsequent to year end, the lending commitment has been reduced to $60 million due to the asset dispositions in the fourth quarter. The banking facilities are currently in the annual review process with finalization expected by the end of April. Total borrowings from these facilities was approximately $26 million at the end of March 1999.

SHARE TRADING INFORMATION FOR BTE.A (TSE)

Share *($/share)*	1998	1997	1996	1995	1994
High	17.50	22.50	14.40	4.45	4.50
Low	3.70	11.75	4.15	2.15	2.40
Close	3.90	15.00	13.15	4.40	3.40
Volume *(thousands)*	33,022	22,056	11,242	4,029	1,178

Business Risk

As a participant in the petroleum and natural gas industry, Baytex monitors and evaluates the various risks associated with its operations on an on-going basis. These include technical risks inherent in the exploration for and development and production of petroleum and natural gas; commodity price, interest rate and foreign currency exchange rate fluctuations; and the environmental impact of the Company's field operations. Many of these risks are out of the control of management but, in an effort to reduce the Company's exposure to the various factors, management has developed a number of key strategies. These include:

1) maintain a highly motivated, energetic and talented staff;
2) focus on geographic areas in which the geological and engineering considerations are well understood by the Company;
3) maintain a sufficiently large prospect inventory to allow for the high-grading of prospects;
4) decrease drilling risk through the proper use of seismic data;
5) locate drillable prospects in proximity to existing infrastructure to ensure timely production;
6) operate prospects which enable the Company to control the timing of revenue and expenditures;

7) use a balanced portfolio approach to market natural gas including a mix of long-term sales contracts, aggregator sales and spot market sales;

8) ensure compliance with all government environmental regulations; and,

9) maintain a level of insurance coverage that is consistent with prudent oilfield practices.

Year 2000 Compliance

The Year 2000 issue (Y2K) is based on the ability of computer software and hardware to recognize the correct date when dealing with time-sensitive data and tasks. When most computer programs were originally written, they were designed to recognize only two digit dates. In 2000 it is widely believed that these programs will become confused and not function properly.

The Y2K problem is complex, with potential implications to many aspects of Baytex's business. The Company recognized its vulnerability to this issue in late 1997 and instituted an evaluation process to determine the key areas of concern. The areas identified were: 1) financial and technical software; 2) computer hardware; 3) office infrastructure and equipment; 4) field production, processing and transportation equipment; and 5) any business conducted by Baytex with third parties who rely on systems and infrastructure that may be affected by the Y2K issue.

Baytex has completed a review of the systems described in the first four areas set out above and has determined that a significant portion of its software, hardware and equipment has been in place for less than three years and is Y2K compliant. In 1998, certain software, hardware and infrastructure that was not Y2K-certified was upgraded with Y2K-certified replacements at a minimal charge. In 1999 Baytex will replace a small number of older desktop computers and one non-critical software package that is not Y2K compliant. These changes are scheduled to be completed prior to July 31, 1999. They were budgeted for 1999 replacement despite the Y2K concern, as they were at the end of their life cycle. The amount budgeted for these replacements comprises approximately one percent of Baytex's total capital budget for 1999. Prior to 1999 Baytex has incurred expenses of less than $100,000 on upgrades and changes directly associated with Y2K concerns.

The most vulnerable area for the Company is the preparedness of the third parties with which Baytex conducts business. These include oilfield service suppliers, oil and natural gas marketers and purchasers, pipeline operators, joint venture partners, banks and insurance companies. Baytex has conducted a survey of this group to determine their Y2K readiness. The majority of these parties have indicated to Baytex they are making an effort to be Y2K compliant. However, none will guarantee 100 percent compliance.

The Company has developed and maintains contingency plans to respond to equipment failures, emergencies and business interruption. Additional contingency planning for Y2K concerns is complicated as it is predicated on the readiness of third parties. However, additional planning in 1999 will focus on identifying risk areas and establishing a team to manage issue resolution and dispatch resources to areas of concern.

Upon the completion of the software and hardware replacements referred to above, Baytex is confident that it has taken all reasonable steps to address Y2K issues critical to its ongoing operations and to minimize any losses that may result. However, given the nature of the Y2K issue, not all risks associated with Y2K are known and therefore not all risks can be mitigated.

Financial

STATEMENTS AND NOTES

Management's Report

In accordance with accounting principles generally accepted in Canada, management has prepared the accompanying financial statements of Baytex Energy Ltd. Financial and operating information presented throughout this annual report is consistent with that shown in the financial statements.

Management is responsible for the integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes. Timely disclosure requires the use of estimates when transactions affecting the current accounting period cannot be finalized or known for certain until future periods. Such estimates are based on judgments made by management using relevant information known at the time.

Independent auditors are appointed by the Company's shareholders to perform an examination of the corporate and accounting records so as to express an opinion on the financial statements. Their examination included a review and evaluation of Baytex's internal control systems and included such tests and procedures, as they considered necessary, to provide reasonable assurance that the financial statements are presented fairly.

The Board of Directors is responsible for ensuring management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through an Audit Committee which meets with management and the independent auditors to satisfy that management's responsibilities are properly discharged, to review the financial statements and recommend that the financial statements be presented to the Board of Directors for approval.

RAYMOND T. CHAN, CA
SENIOR VICE PRESIDENT
AND CHIEF FINANCIAL OFFICER

JOHN G. LEACH, CA
VICE PRESIDENT,
FINANCE AND ADMINISTRATION

Auditors' Report

TO THE SHAREHOLDERS OF BAYTEX ENERGY LTD.:

We have audited the balance sheets of Baytex Energy Ltd. as at December 31, 1998 and 1997 and the statements of operations and retained earnings and changes in financial position for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 1998 and 1997 and the results of its operations and changes in its financial position for the years then ended in accordance with generally accepted accounting principles.

Deloitte & Touche LLP

CHARTERED ACCOUNTANTS

CALGARY, CANADA
FEBRUARY 26, 1999

Financial Statements

BALANCE SHEETS

AS AT DECEMBER 31 (*$ thousands*)	1998	1997
Assets		
Current assets		
Accounts receivable	$ 22,793	$ 30,523
Properties held for sale (NOTE 3)	46,106	–
	68,899	30,523
Petroleum and natural gas properties (NOTE 4)	344,101	413,308
	$413,000	$443,831
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	$ 26,849	$ 62,865
Long-term debt (NOTE 5)	157,093	98,555
Provision for future site restoration costs	11,710	10,348
Deferred income taxes	1,856	26,267
	197,508	198,035
Shareholders' Equity		
Share capital (NOTE 6)	209,782	204,378
Retained earnings	5,710	41,418
	215,492	245,796
	$413,000	$443,831

ON BEHALF OF THE BOARD

DIRECTOR

DIRECTOR

Financial Statements

STATEMENTS OF OPERATIONS AND RETAINED EARNINGS

YEARS ENDED DECEMBER 31 (*$ thousands, except per share data*)	1998	1997
Revenue		
Petroleum and natural gas sales	$102,337	$123,839
Royalties, net of ARTC	(14,720)	(19,579)
Other	778	775
	88,395	105,035
Expenses		
Operating	30,095	32,598
General and administrative	3,375	3,311
Interest on long-term debt	9,988	4,342
Depletion, depreciation and amortization	106,775	41,887
Site restoration costs	2,227	2,634
	152,460	84,772
(Loss) income before income taxes	(64,065)	20,263
Income taxes (NOTE 7)		
Current	1,017	905
Deferred	(26,700)	8,369
	(25,683)	9,274
Net (loss) income	(38,382)	10,989
Retained earnings, beginning of year	41,418	41,312
Business combination recovery (costs) (NOTE 2)	2,674	(10,883)
Retained earnings, end of year	$ 5,710	$ 41,418
Net (loss) income per share		
Basic	$ (1.12)	$ 0.36
Fully diluted	$ (1.12)	$ 0.36

Financial Statements

STATEMENTS OF CHANGES IN FINANCIAL POSITION

YEARS ENDED DECEMBER 31 (*$ thousands, except per share data*)	1998	1997
Cash provided by (used in):		
Operating activities		
Net (loss) income	$(38,382)	$ 10,989
Depletion, depreciation and amortization	106,775	41,887
Site restoration costs	2,227	2,634
Deferred income taxes	(26,700)	8,369
Cash flow from operations	43,920	63,879
Change in non-cash working capital	(31,219)	16,696
	12,701	80,575
Financing activities		
Increase in long-term debt	58,936	25,555
Decrease (increase) in business combination costs	4,963	(17,715)
Issue of shares (net of issue expenses)	8,820	64,686
	72,719	72,526
Investing activities		
Petroleum and natural gas property expenditures	(128,424)	(177,743)
Disposal of petroleum and natural gas properties	89,110	11,089
Properties held for sale	(46,106)	–
	(85,420)	(166,654)
Change in cash during the year	–	(13,553)
Cash, beginning of year	–	13,553
Cash, end of year	$ –	$ –
Cash flow from operations per share		
Basic	$ 1.29	$ 2.10
Fully diluted	$ 1.25	$ 2.01

YEARS ENDED DECEMBER 31, 1998 AND 1997

NOTE 1 Significant Accounting Policies

The financial statements of the Company have been prepared in accordance with generally accepted accounting principles within the framework of the accounting policies summarized as follows:

Petroleum and natural gas operations

The Company follows the full cost method of accounting whereby all costs relating to the exploration for and development of petroleum and natural gas reserves are capitalized in one Canadian cost centre and charged against income, as set out below. Such costs include land acquisition, drilling, geological and geophysical and overhead expenses related to exploration and development activities. These costs are depleted and depreciated on a unit of production method using estimated gross proven petroleum and natural gas reserves as determined by independent engineers. For purposes of this calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of gas equates to one barrel of oil. Costs of acquiring and evaluating unproven properties are excluded from costs subject to depletion and depreciation until it is determined whether proven reserves are attributable to the properties or impairment occurs. Costs of production facilities are depreciated on a unit of production basis.

Gains or losses on sales of properties are recognized only when crediting the proceeds to costs would result in a change of 20 percent or more in the depletion rate.

The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test (the "ceiling test"). Under this test, an estimate is made of the ultimate recoverable amount from future net revenues using proven reserves and year-end prices, plus the net costs of major development projects and unproven properties, less future removal and site restoration costs, overhead, financing costs and income taxes. If the net carrying costs exceed the ultimate recoverable amount, additional depletion and depreciation is provided.

Provision for future site restoration costs

Estimates are made of the future site restoration costs relating to the Company's petroleum and natural gas properties at the end of their economic life, based on year-end values, in accordance with current legislative requirements and industry practice. Annual charges are provided for on a unit of production method. Actual expenditures incurred are applied against the provision for future site restoration costs.

Joint interests

A portion of the Company's exploration, development and production activities are conducted jointly with others. These financial statements reflect only the Company's proportionate interest in such activities.

Foreign currency translation

Foreign currency denominated monetary items are translated into Canadian dollars at the exchange rate in effect at the balance sheet date. Unrealized gains or losses on long-term debt are deferred and amortized over the remaining term of the debt instrument.

Revenue and expenses are translated at the monthly average rate of exchange. Translation gains and losses are included in net income.

Financing costs

Financing costs related to the issuance of the senior secured term notes are deferred and amortized over the term of the notes.

Hedging transactions

The Company periodically utilizes certain financial instruments to hedge exposures related to commodity prices and foreign exchange fluctuations on a portion of its crude oil and natural gas production. Gains and losses realized on these transactions are reported as adjustments to revenue when related production is sold.

Flow-through shares

The Company has financed a portion of its exploration and development activities through the issue of flow-through shares. Under the terms of the flow-through share agreements, the tax attributes of the related expenditure are renounced to the subscribers. Accordingly, the carrying value of the expenditures incurred and the shares issued are recorded net of tax benefits renounced to the subscribers.

NOTE 2 Business Combination

On October 7, 1997, pursuant to an offer to purchase all of the common shares of Dorset Exploration Ltd. ("Dorset") and an accompanying take-over bid circular dated September 15, 1997, the Company entered into a business combination with Dorset, a company with petroleum and natural gas properties located primarily in western Canada. In October 1997, the Company issued 15,573,175 Class A shares at a rate of 0.48 Class A shares for each Dorset common share, resulting in the former shareholders of the Company holding 53 percent and the former shareholders of Dorset holding 47 percent of the 33,707,000 outstanding Class A shares of the combined company. On October 7, 1997, the date of the closing of the transaction, the closing market price of the Company's Class A shares was $21.25 per share.

The business combination was accounted for using the pooling of interests method of accounting. The book values of assets and liabilities at the date of the acquisition approximated those at September 30, 1997, and were as follows:

(thousands)	BAYTEX	DORSET
Current assets	$ 7,835	$ 11,493
Petroleum and natural gas properties	144,796	246,526
	152,631	258,019
Current liabilities	(17,055)	(13,874)
Long-term debt	(6,059)	(85,705)
Provision for future site restoration costs	(623)	(9,498)
Deferred income taxes	(1,050)	(28,730)
Net assets	$ 127,844	$ 120,212

The operating results of Baytex and Dorset for the 9 months ended September 30, 1997 were as follows:

(thousands)	BAYTEX	DORSET
Petroleum and natural gas properties	$ 25,013	$ 66,475
Net income	$ 3,143	$ 3,278

Costs of $17,715,000 ($10,883,000 net of tax), consisting mainly of professional fees, advisory fees and other costs, which were estimated to be incurred to effect the business combination, were charged to retained earnings in 1997. In 1998, $4,963,000 ($2,674,000 net of tax) of these estimated costs were not incurred and accordingly reversed in retained earnings in the current year.

NOTE 3 Properties Held for Sale

During the fourth quarter of 1998, the Company commenced a program of divestiture in which the Company actively made available for sale a number of its petroleum and natural gas properties. As at December 31, 1998 a total of $46,106,000 of such transactions were in various stages of completion. This amount have been reclassified from property, plant and equipment to properties held for sale at December 31, 1998. Subsequent to year end, these proceeds were received and applied to the outstanding bank loan.

NOTE 4 Petroleum and Natural Gas Properties

AS AT DECEMBER 31 *(thousands)*	1998	1997
Petroleum and natural gas properties	$ 653,227	$ 615,644
Accumulated depletion and depreciation	(309,126)	(202,336)
	$ 344,101	$ 413,308

During 1998, $1,034,000 (1997 – $3,907,000) of general and administrative expenses relating to exploration and development activities were capitalized. In calculating the depletion provision for 1998, $52,440,000 (1997 – $48,570,000) of costs relating to undeveloped properties were excluded from costs subject to depletion.

The ceiling test was calculated using year-end prices, costs and reserves. The Company incurred a ceiling test writedown of $38,110,000, net of deferred tax recovery of $26,700,000.

NOTE 5 Long-Term Debt

AS AT DECEMBER 31 *(thousands)*	1998	1997
Senior secured term notes (US $57,000,000)	$ 87,239	$ –
Bank loan	69,854	98,555
	$ 157,093	$ 98,555

Senior secured term notes

On November 13, 1998, the Company issued U.S. $57,000,000 of senior secured term notes, bearing interest at 7.23 percent payable quarterly with principal repayable on November 13, 2004. These notes are governed by financial and other corporate covenants and are secured by a charge over all of the Company's assets, which security is shared pari passu with the banking facilities.

Bank loan

The bank loan consists of an operating loan and a revolving term loan provided by a Canadian chartered bank. The facilities bear interest at the Bank's prime lending rate and are secured by a charge over all of the Company's assets, which security is shared pari passu with the senior secured term notes. The facilities are subject to annual review and include a total borrowing commitment of $85,000,000 at December 31, 1998.

NOTE 6 Share Capital

(a) Authorized

Unlimited number of Class A voting shares

Unlimited number of Class B non-voting shares. On April 15, 1997, the Company exercised its option to call the Class B shares for conversion at a rate of 0.072098 Class A share for each Class B share.

(b) Issued

	1998		1997	
(thousands)	# SHARES	AMOUNT	# SHARES	AMOUNT
Class A				
Balance, beginning of year	33,791	$204,378	26,980	$126,728
Stock options exercised (NOTE 6(C))	235	1,332	1,413	12,939
Public offerings	–	–	3,000	49,500
Flow-through special warrants exercised (NOTE 6(D))	–	–	1,482	19,419
Flow-through shares issued (NOTE 6(E))	1,306	7,765	409	5,198
Conversion of Class B shares	–	–	507	3,470
Share issue costs, net of deferred tax	–	(276)	–	(1,637)
Tax effect of renounced expenditures	–	(3,417)	–	(11,239)
Balance, end of year	35,332	$209,782	33,791	$204,378
Class B				
Balance, beginning of year	–	–	7,040	3,470
Conversion to Class A shares	–	–	(7,040)	(3,470)
Balance, end of year	–	–	–	–
Flow-Through Special Warrants				
Balance, beginning of year	–	–	1,482	19,419
Exchanged for Class A shares	–	–	(1,482)	(19,419)
Balance, end of year	–	–	–	–

The number of shares and per share information presented in these financial statements have been adjusted to reflect the business combination with Dorset in October, 1997 (note 2).

(c) Stock options

At December 31, 1998, 3,204,375 Class A shares of the Company are reserved under a Stock Option Plan for issuance to eligible participants. Options for 3,030,375 shares (1997 – 1,262,200) were outstanding with exercise prices ranging from $2.15 per share to $18.75 per share (weighted average price being $8.775 per share) and expiration dates between August 1999 and May 2002.

(d) Flow-through special warrants

During 1997, the Company issued 1,481,500 flow-through special warrants at $13.50 per special warrant. These special warrants were converted into 1,481,500 Class A shares of the Company. As at December 31, 1998, all of the proceeds had been expended on qualifying oil and gas expenditures.

(e) Flow-through shares

In accordance with the terms of the Company's various flow-through share offerings, and pursuant to certain provisions of the Income Tax Act (Canada), the Company committed to renounce, for income tax purposes, exploration expenditures to the purchasers of its flow-through shares in the aggregate amount of $7,765,000 (1997 – $5,198,000).

NOTE 7 Income Taxes

The provision for income taxes has been computed as follows:

(thousands)	1998	1997
(Loss) income before income taxes	$ (64,065)	$ 20,263
Expected income taxes at the statutory rate of 44.6%	$ (28,573)	$ 9,037
Increase (decrease) in taxes resulting from:		
Crown royalties	5,703	7,087
Resource allowance	(7,237)	(8,451)
Alberta royalty tax credit	(656)	(863)
Non-tax base depletion	4,029	1,542
Other	34	17
Large Corporation Tax and provincial capital tax	1,017	905
Provision for income taxes	$ (25,683)	$ 9,274

Petroleum and natural gas properties with a net book value of $31,325,000 at December 31, 1998 (1997 – $34,000,000) has no cost base for income tax purposes. The majority of these amounts arose as a result of the issuance of flow-through shares.

NOTE 8 Financial Instruments

The Company's financial instruments recognized in the balance sheet consist of accounts receivable, current liabilities and long-term borrowings. The estimated fair values of recognized financial instruments have been determined based on the Company's assessment of available market information and appropriate valuation methodologies; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

The fair values of financial instruments other than long-term borrowings approximate their carrying amounts due to the short-term maturity of these instruments. The senior secured term notes disclosed in Note 5 and the Company's bank loan represent their fair values.

The Company is party to certain derivative financial instruments, such as crude oil and natural gas swap contracts. The Company enters into these contracts for hedging purposes only in order to protect its cash flow on future sales from the potential adverse impact of low oil and gas prices. The swap contracts reduce the fluctuations in sales revenues by locking in fixed prices and exchange rates on a portion of its oil and gas sales. The Company does not use derivative instruments involving multipliers or leverage.

The Company has sold forward 1,500 barrels per day of heavy crude oil at an average of the settlement price quotes for the prompt month NYMEX light sweet crude oil contract for the calendar month of delivery, less a fixed differential of U.S. $4.60 per barrel, expiring December, 1999. In addition, the Company has hedged a notional quantity of 4,000 barrels per day at an average of $20.51 Canadian per barrel, expiring December, 1999, with an option by the counterparty to extend 1,000 barrels per day at a price of $21.20 per barrel from January 1, 2000 through to June 30, 2000.

NOTE 9 Commitments

The Company has committed to the following aggregate annual payments for leases of facilities and premises:

	(thousands)
1999	$3,709
2000	$3,709
2001	$3,709
2002	$2,432
2003	$1,046

NOTE 10 Uncertainty due to the Year 2000 Issue

The Year 2000 Issue arises because many computerized systems use two digits rather than four to identify a year. Date-sensitive systems may recognize the year 2000 as 1900 or some other date, resulting in errors when information using year 2000 dates is processed. In addition, similar problems may arise in some systems which use certain dates in 1999 to represent something other than a date. The effects of the Year 2000 Issue may be experienced before, on or after January 1, 2000, and, if not addressed, the impact on operations and financial reporting may range from minor errors to significant systems failure which could affect an entity's ability to conduct normal business operations. It is not possible to be certain that all aspects of the Year 2000 Issue affecting the entity, including those related to the efforts of customers, suppliers, or other third parties, will be fully resolved.

NOTE 11 Comparative Figures

Certain comparative figures have been reclassified to conform to the current year's presentation.

Five Year Summary

($ thousands, except per share amounts)		1998	1997	1996	1995	1994
Financial	Revenue	**102,337**	123,839	80,964	62,234	62,686
	Cash flow from operations	**43,920**	63,879	50,924	35,807	41,407
	per share basic*	**1.29**	2.10	2.19	1.76	2.40
	Net income (loss)	**(38,382)**	10,989	10,500	5,051	9,512
	per share basic*	**(1.12)**	0.36	0.45	0.25	0.55
	Capital expenditures, net	**39,314**	166,654	109,062	45,743	92,737
	Working capital (deficiency)	**42,050**	(32,342)	(2,093)	(5,625)	(5,314)
	Long-term debt	**157,093**	98,555	73,000	69,622	66,979
	Total assets	**413,000**	443,831	339,256	235,453	219,393
Operations	Production					
	Crude oil and NGLs (bbls/d)	**8,992**	8,895	7,454	7,290	7,894
	Natural gas (mmcf/d)	**75.9**	78.7	52.8	38.8	31.8
	Barrels of oil equivalent (boe/d)	**16,582**	16,765	12,736	11,169	11,075
	Reserves					
	Crude oil and NGLs (mbbls)					
	Proven	**54,395**	55,765	21,963	16,360	20,029
	Probable	**28,807**	28,374	6,224	3,568	3,245
	Total	**83,202**	84,139	28,187	19,928	23,274
	Natural gas (mmcf)					
	Proven	**105,724**	201,630	184,431	136,912	114,012
	Probable	**44,289**	71,337	56,983	27,421	13,011
	Total	**150,013**	272,967	241,414	164,333	127,023
	Wells drilled (gross)					
	Oil	**91**	79	77	56	105
	Gas	**47**	49	53	37	36
	Other	**–**	–	1	3	23
	Dry	**33**	58	56	28	42
	Total	**171**	186	187	124	206
	Undeveloped land holdings (thousands of net acres)	**934**	1,094	1,182	843	948

** 1994 through 1996 amounts are shown pooling Baytex's results with Dorset's. Per share numbers reflect each Dorset share exchanged for 0.48 Baytex share.*

Corporate Information

Board of Directors

JOHN A. BRUSSA
Partner
Burnet, Duckworth & Palmer

W.A. BLAKE CASSIDY
Retired Banker

RAYMOND T. CHAN
Senior Vice-President
Baytex Energy Ltd.

FRED C. COLES
Executive Chairman,
Applied Terravision Systems Ltd

DENNIS L. NERLAND
Partner
Shea Nerland Calnan

DALE O. SHWED
President
Baytex Energy Ltd.

Officers

DALE O. SHWED
President and Chief Executive Officer

RAYMOND T. CHAN, CA
Senior Vice-President and
Chief Financial Officer

JOHN G. LEACH, CA
Vice-President, Finance
and Administration

S. DALE MCAULEY
Vice-President, Operations

RICHARD W. NADEN
Vice-President, Production

DERIC S. ORTON
Vice-President, Land

GARRY J. WASYLYCIA
Vice-President, Exploration

GREGORY G. TURNBULL
Secretary
Partner, Code Hunter Wittmann

Executive Offices

SUITE 2200, BOW VALLEY SQ. II
205 - 5th Avenue S.W
Calgary, Alberta T2P 2V7
Phone: (403) 269-4282
Fax: (403) 205-3845
Internet address: www.baytex.ab.ca

Auditors

DELOITTE & TOUCHE LLP

Bankers

ROYAL BANK OF CANADA

Legal Counsel

CODE HUNTER WITTMANN
BURNETT, DUCKWORTH & PALMER

Reserves Engineers

OUTTRIM SZABO ASSOCIATES LTD

Transfer Agent

MONTREAL TRUST
COMPANY OF CANADA

Exchange Listing

TORONTO STOCK EXCHANGE
STOCK SYMBOL BTE.A

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PRINTED IN CANADA

BAYTEX ENERGY LTD.

SUITE 2200, BOW VALLEY SQ. II
205 - 5TH AVENUE S.W
CALGARY, ALBERTA T2P 2V7